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Modelling Generator Maintenance Scheduling Costs in Deregulated Power Markets

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ABSTRACT

Generating companies use the maintenance cost function as the sole or main objective for creating the maintenance schedule of power generators. Usually only maintenance activities related costs are considered to derive the cost function. However, in deregulated markets, maintenance related costs alone do not represent the full costs of generators. This paper models various cost components that affect the maintenance activities in deregulated power markets. The costs that we model include direct and indirect maintenance, failures, interruptions, contractual compensation, rescheduling, and market opportunity. The loss of firm's reputation and selection of loyalty model are also considered using the Analytic Hierarchy Process (AHP) within an opportunity cost model. A case study is used to illustrate the modelling activities. The enhanced model is utilised in generator maintenance scheduling cases. The experimental results demonstrate the importance and impact of market related costs in maintenance schedules.

KEY WORDS: Maintenance, opportunity cost, deregulated market, reputation, AHP

1. Introduction

The electricity sector in many countries has moved from a centralized structure to deregulated markets separating the integrated power system into various competitive entities. This has created an open electricity market pool by allowing competition with respect to the supply of power and allowing consumers to choose their preferred supplier of electric energy [6, 18, 32]. In power systems, generators must be maintained in order to supply electricity with high reliability. Power generating companies (GENCOs) apply different maintenance strategies, such as reliability centre maintenance [4, 29], corrective maintenance [4], preventive maintenance [6, 7], age-based maintenance [19] etc., to achieve their objectives in terms of quality and cost. Regardless of the type of maintenance carried out, the generator units must be taken out of service for a period of time ranging from several hours to several weeks [13, 32]. In the deregulated environment, the decision when to take the generator out of service depends on various factors such as the effect of maintenance outages on the overall system, reliability, loss of services, loss of firm's reputation and loss of revenue [9, 10]. The coordination of this is usually done by the Independent System Operator (ISO).

This paper concentrates on the maintenance cost modelling of power generators for GENCOs in a deregulated environment. There are different costs associated with generator maintenance activities in deregulated power markets that influence maintenance scheduling and other planning activities. Reducing the maintenance cost is one of the main objectives in scheduling power system maintenance but this can be problematic. As the major factor for scheduling maintenance, formulating the problem requires the maintenance cost to be carefully modelled to reflect the real-world scenarios. It must be accurately quantified to ensure the optimal solution found represents a realistic optimised schedule [7].

In Al-Arfaj et al. [1] preliminary modelling concepts and opportunity costs of planning generator maintenance have been introduced. We extend these ideas by developing two complete maintenance cost models under "no-failure" and "failure" cases. The developed models also include "reputational costs", "interruption" and "contractual compensation"[1] (hereafter "compensation") costs. The reputational cost is quantified with the selection of the best loyalty model to minimise the loss using the Analytic Hierarchy Process (AHP). The paper also shows the data gathering process for the proposed cost models. The developed cost model has been utilised in two generator maintenance scheduling cases to demonstrate the impact of the "reputational costs" with the AHP loyalty models on the maintenance schedule.

[1] In case of failure to generate power, GENCOs are obliged to supply the contractual volume by buying in the spot market. Hence the compensation cost will be equal to the difference between spot price and contracted price (see expression 6 for further details).

2. Related work

Maintenance cost in power systems includes direct and indirect costs. Examples of direct maintenance costs include the costs of labour, spare parts, and cleaning materials. The indirect costs include costs for inventory, shipment, indirect labour (e.g. health insurance), test equipment, etc. Most formulations, however, concentrate only on total (fixed and variable) direct maintenance costs in the delivery of maintenance cost models [9, 22, 32]. A general model for scheduling maintenance is presented in [32], which uses maintenance costs of power generating units and the energy production cost within the objective function. This model has been described with different objective functions [26], such as minimising total operating cost or minimising the loss of revenue, but using the same maintenance cost function. The model presented by Leou [23] focuses on improving reliability by maintaining the units as early as possible. The model is a cost minimisation model which includes the direct maintenance cost. The maximisation of the profit objective function was considered by Chen *et al.* [9] to find the best maintenance schedule for generators in deregulated power systems.

The maintenance model for deregulated power systems should also include market related costs such as opportunity costs (revenue lost due to opportunity foregone), compensation costs and failure costs, in addition to the classical maintenance cost. The opportunity cost was introduced as an influencing factor in modelling cost and electricity pricing in restructured power systems [3, 8, 25]. Baughman *et al.* [3] developed a mathematical model for real-time pricing of electricity, which includes selected ancillary services and incorporates constraints on power quality and environmental impact that often influence the operation of a power system. The model uses optimal nodal specific real-time prices both for real and reactive power that incorporate additional premiums, reflecting the effects of the various engineering and environmental operating constraints. The opportunity cost of market participation was included in the generator maintenance scheduling model in [25].

Chattopadhyay [8] developed a model that considered the trade-off between short- and long-term objectives to determine optimal generator maintenance profiles. All major costs associated with maintenance, namely direct maintenance expenses, opportunity costs, replacement costs and contractual compensation, are explicitly recognized in the model. Clearly, maintenance cost representations in this model differ from the traditional models.

In the deregulated environment a company can have only limited information on the activity of other companies, adding uncertainties to its own planning decisions [10, 17, 20]. In the competitive market, the interaction between GENCOs and the ISO can affect the profit of GENCOs, who are to maximise the profit against the time-varying market prices. Kim *et al.* [20] presented a game-theoretical framework taking GENCOs as game players to maximise their profit in a competitive environment. Feng *et al.* [17] investigated an iterative maintenance scheduling scheme in power markets, considering the influence of unexpected generating unit failures. Conejo *et al.* [10] proposed a coordination method based on an incentive/disincentive programme between the ISO and GENCOs to overcome their conflicting maintenance scheduling objectives in a competitive environment. To attain the preferred level of reliability, the model proposes reallocating the maintenance outages to GENCOs that are making the least profit. This model aims to provide a compromise solution to both GENCOs and the ISO. This indicates that there is a cost pertaining to GENCOs' coordination, which is imposed by the ISO to ensure an appropriate distribution of maintenance outages over the period. Along with the competitive prices, GENCOs should also play an important role in delivering high reliability and customer care to enhance their corporate reputation and brand value by acting in a responsible manner which can make a significant impact on customer retention [6, 33]. Cai et al. [6] analysed GENCOs' customers[2] who would switch to a competitor under various price discounts and service attributes (reliability, renewable power, energy conservation assistance, and customer service).

What follows from the above discussion is that different cost components have an effect on maintenance scheduling and that there is a need for a single model which incorporates all maintenance cost components in order to analyse their effect on GENCOs. Also, many of the cost components suggested in the literature are assigned to fixed values, restricting their use in optimisation models. In this paper, we model a wide range of cost components that affect the maintenance activities of deregulated GENCOs. We also model GENCOs' reputational cost due to the maintenance activities of generators. We propose loyalty models to minimise the loss of firm's reputation using the AHP.

The AHP has been applied to a number of applications in the literature [28]. The AHP approach is a subjective methodology where information and the priority weights of criteria may be obtained from a decision-maker using direct questioning or a questionnaire method [16]. It is a decision approach designed to solve a complex multiple-criteria based problem in a number of application domains. Nigim *et al.* [28] use the AHP to study the impact of Special Protection Schemes' (SPSs) mis-operations in a power system due to hidden failures in the SPS at the most critical bus locations. Hidden failures (i.e. failures that are not apparent during the normal operation of a system which become exposed during a fault) are major contributing factors for a serious system disturbance to happen. The AHP reduces time and effort in locating the most and least vulnerable SPS as it integrates an expert's service experience in the field and probability tools. Sato and Kataoka [31] have introduced customer satisfaction surveys and analysed customers' perception of telecommunication services. All customers are surveyed regarding items such as service order reception, provisioning and repairs. The AHP was used to investigate each customer's perception of the importance of the Quality of Service, and to estimate the overall customer satisfaction weighted by importance. Medjoudj *et al.* [27] developed an application of multi-criteria techniques for decision

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[2] GENCOs customers include suppliers, retailers, traders, brokers and end users.

making in an electrical distribution system for customer satisfaction and financial success of the company. Cost-benefit analysis and the AHP were introduced to overcome the reputational issue of the company. A particular concentration is given to the AHP because it makes the selection process very clear with huge benefits for a company assuring public services. The AHP is applied to choose the best alternative to provide customer satisfaction and financial success. The result shows that both cost-benefit analysis and the AHP methods converge to an investment need.

In this paper we will focus on the application of an AHP technique to select the best alternative (loyalty model - LM) which contains the most important criteria that affect "reputational cost". However, the concepts of the developed model will be used to mathematically quantify the reputational cost to be included in the cost model of the maintenance scheduling of deregulated power systems.

3. Maintenance Models for Deregulated Power Markets

3.1 Notations

The maintenance models for deregulated power markets are formulated as an optimisation problem with single and multiple objectives and a set of constraints. The following notations are used to represent the maintenance costs in the sections below.

AM_t	Available manpower at period t
$Cma_{it}(s)$	Cost (\$) of maintenance actions for generator *i* at time *t* for maintenance strategy *s*
$Cf_{it}(s)$	Cost (\$) of failure for generator *i* at time *t* for maintenance strategy *s*
$Cr_{it}(s)$	Repair (or replacement) cost (\$) for generator *i* at time *t* for maintenance strategy *s*
$C_i(g_i)$	Generation cost function (\$) of generator *i*
D_i	Duration of maintenance for generator *i*
Ep_i	Earliest period for maintenance of generator *i* to begin
$\text{Exp}(C_{it})$	Total expected generator maintenance cost (\$) for generator *i* at time *t*
f_i	The probability of generator unit failure
$g_{it,sched}$	Power (MW) scheduled to be supplied by generator *i* at time *t*
i	Index for generators
I	Set of generator indices
$ICf_{it}(s)$	Interruption cost (\$) due to failure of generator *i* at time *t* for maintenance strategy *s*
Lp_i	Latest period for maintenance of unit *i* to end
L_t	Anticipated load delivery for period *t*
M_{it}	Manpower needed by unit *i* at period *t*
N	Total number of generators

$oppl_{it}$ No-bids losses ($) of generator i at time t

$oppf_{it}$ Contractual compensation cost ($) to due to failure of generator i at time t

$oppi_{it}$ Reputational cost ($) due to failure or planned maintenance of generator i at time t

RC_{it} Rescheduling cost ($) due to failure or planned maintenance of generator i at time t

R_t Anticipated load reserve for period t

T Index of time periods

T Total number of periods in planning horizon, e.g. weeks

3.2 Deregulated Market Structure

This section briefly introduces the electricity market structure and electricity prices considered in this paper. In a competitive environment, GENCOs (who produce electricity), suppliers (who supply the electricity to the end users), and other intermediaries (such as traders, retailers, brokers) can freely trade electricity through one or many free markets [5, 14, 18, 24]. The market structure considered in this paper is represented by two market segments: a day-ahead market and a real-time hourly (spot) market. The power system is operated by an ISO to balance supply and demand of electricity in real-time. Generally the ISO does not own any generators but has the responsibility of balancing in order to maintain both security and reliability of power systems. The ISO does this by scheduling the generation level of participating GENCOs.

In the day-ahead-market, the ISO conducts an auction of electricity delivery for each hour of the next operating day [14, 18]. GENCOs bid to supply a fixed unit of electricity based on their ability to produce in the specified period on the following day. The ISO accepts bids from generators on an hourly basis to meet the electricity demands of the end users. The last bid accepted for a particular hour is the price the ISO pays to all generators. This price is called the market clearing price (MCP). MCPs are calculated for each hour of the next operating day based on bids submitted to the ISO. The generator receives feedback from the MCP and load profiles for the day-ahead electricity market on a daily basis along with the day's generator schedule from the ISO.

Some customers, instead of purchasing from the day-ahead market, can obtain their electricity from generators through individual contracts, known as bilateral contracts. Using bilateral contracts, sellers and buyers enter into transactions where the quantities traded and the prices are negotiated. In some cases these contracts may be indexed to the MCP. The MCP, therefore, can affect the price that direct access customers pay for electricity [21].

The ISO runs a real-time hourly spot (wholesale) market where generators offer real-time electricity delivery at spot prices [14]. If their offer is used, the payment will be made to the generators at the spot price. The ISO utilises the real-time hourly spot market to ensure that the supply and demand are equal and to alleviate any network problems that may occur. Also, the real-time hourly spot market provides a balancing mechanism if GENCOs and/or customers deviate from contracted positions. GENCOs/customers specify their prices for short-term supply/demand to participate in the spot market. The price of electricity in this market is called the spot market price (SMP). SMP is usually low during off-peak and high during peak loads.

If a generator experiences an outage after acceptance of a bid by the ISO, it must buy replacement electricity from the spot market to fulfil its commitments. However, the generator is still paid by the ISO at the agreed day-ahead MCP. It incurs a loss when the SMP is greater than the day-ahead MCP [14]. In competitive markets GENCOs must factor failures and the maintenance of generators in their bidding strategies to calculate their production.

3.3 Direct and Indirect Maintenance Costs

There are direct and indirect costs related to the maintenance actions in power systems. The direct costs include labour (L_{it}) and material (M_{it}) costs ($) for generator *i* at time *t*. The indirect costs include indirect labour (IL_{it}) (e.g. health care) and indirect material (IM_{it}) (i.e. test equipment) costs ($) for generator *i* at time *t*. Taking these into account, the direct and indirect maintenance costs can be expressed as,

$$Cma_{it}(s) = L_{it} + M_{it} + IM_{it} + IL_{it} \qquad (1)$$

3.4 Cost of Failure

This is the cost of repair or replacement due to failures. Referring to [4] the cost of failure can be modelled as,

$$Cf_{it}(s) = \lambda_{it}(s) \cdot Cr_{it}(s) \qquad (2)$$

Where, $\lambda_{it}(s)$ is the failure rate for generator *i* at time *t* for maintenance strategy *s*.

3.5 Opportunity Costs

The opportunity costs can be found in the two scenarios: when the generator is subjected to planned maintenance, or when it fails between maintenance periods. In this section we model five different components of opportunity costs.

3.5.1 *No-Bids Losses*

Generators can trade electricity in a spot market with immediate settlement of payment and delivery. Generally, this provides an opportunity for the generators to sell the electricity at a higher price; however, this will also increase the risk of not being able to sell. This opportunity cost can be expressed in terms of real-time Spot Market Price at time *t* (SMP_t) ($/MW) and day-ahead Market Clearing Price at time *t* (MCP_t) ($/MW).

For each hour an MCP is obtained which is equal to the incremental cost of supplying the next unit of power. The day-ahead MCPs can be estimated using an appropriate distribution function in a time series model. For simplicity and demonstration purposes, we assume that they follow a normal distribution. Therefore, the generators can then estimate MCP for each hour of the day from normal distribution of historical MCP data. In a normal situation the SMP (spot price) follows the pattern of the MCP; it can reach very high values occasionally and can even be less than the MCP during the off-peak periods [14]. The real-time hourly SMP is modelled using:

$$SMP_t = MCP_t(1+\alpha) \qquad (3)$$

In reality SMP varies within a range (the range increases with the increase in market volatility) or regulators may put a cap on the price. Consequently the value of α varies within a range. We can calculate the upper and lower bounds of α using historical data of SMP and average MCP for a period. Let us define maximum value of SMP as SMP_{max}, minimum value of SMP as SMP_{min} and average MCP as MCP_{ave} for a representative period. The minimum and maximum values of α can be calculated using expression (3) as follows: For the lower bound $\alpha_{min} = (SMP_{min} / MCP_{ave}) - 1$; and for the upper bound $\alpha_{max} = (SMP_{max} / MCP_{ave}) - 1$.

Bessembinder and Lemmon [5] and Longstaff and Wang [24] report that the values of MCP and SMP are similar on average and somehow related. The average value of SMP, however, is more volatile and can be very different from the average value of MCP in a given period. In the absence of historical data for SMP*,* we assume that SMP can be within the range of (0.1* average *MCP*) and (10* average *MCP*). Based on these values, α varies in the range of (-0.9, 9).

Let us assume that all generators have an opportunity to participate in the day-ahead or real-time spot markets. No-bids loss occurs when the generator is under maintenance or when it ceases working because of a failure. The loss is the difference between the earnings from the market participation and the generation cost. This cost is summarised in expression (4):

$$oppl_{it} = \begin{cases} g_{it,sched} SMP_t - C_t(g_{it,sched}), & \text{for spot market,} \\ g_{it,sched} MCP_t - C_t(g_{it,sched}), & \text{for day-ahead market.} \end{cases} \qquad (4)$$

Expression (4) applies for both no-bids loss ($) due to maintenance or failure of generator *i* at time *t*, ($opplm_{it}$) and ($opplf_{it}$) respectively. For convenience we represent these two terms separately as in expression (5):

$$\left\{ \begin{array}{ll} opplm_{it} & \text{in case of planned maintenance} \\ opplf_{it} & \text{in case of failure} \end{array} \right\} \qquad (5)$$

No-bids loss is included as one of the components in the expected maintenance cost (see Section 3.6) which we wish to minimise while scheduling maintenance activities (see expression (14)). Note that the expected maintenance cost (and the no-bids loss as a part of this) is calculated only for the generators which are taken off the line for maintenance (as the unit *i* is off for maintenance at time *t*).

3.5.2 *Contractual Compensation Cost*

Acceptance of a bid/contract to supply electricity in the day-ahead market does not ensure GENCO's profit, as a forced outage can occur. If outage occurs the GENCO is required to buy electricity from the real-time spot market to meet its contractual obligation at the SMP. However, it receives payment at the agreed day-ahead MCP rate. Therefore, the compensation cost due to a failure can be positive (loss) or negative (gain), depending on the difference between SMP and MCP as summarised in expression (6):

$$oppf_{it} = g_{it,sched}(SMP_t - MCP_t) \qquad (6)$$

When the loss/profit expressed in (4) and the compensation cost (6) are summed up, we obtain the potential loss of not being able to supply electricity due to the outage of generator *i* at time *t*.

3.5.3 *Rescheduling Cost*

Referring to [10], another component of opportunity cost is the ISO payment (incentive) to each GENCO for maintenance scheduling adjustment (Rescheduling Cost of generator *i* at time *t* (RC_{it})); the adjustment cost is defined as:

$$RC_{it} = \tau \cdot \omega_t \cdot g_i \qquad (7)$$

Where τ is the constant used to express the incentive/disincentive (ω_t) in cost units ($) per MW, and g_i is the generator capacity in MW. These rescheduling costs occur when the generator is under maintenance and when it stops working because of a failure. In the case of failure, the GENCO may be penalized (disincentive) for making the ISO adjust the maintenance schedule of other generators. For convenience we represent them here separately as:

$$\left\{\begin{matrix} RCm_{it} & \text{in case of planned maintenance} \\ RCf_{it} & \text{in case of failure} \end{matrix}\right\} \qquad (8)$$

3.5.4 *The Reputational Cost*

In the case of generator failure or maintenance, GENCOs are responsible for delivering the contracted power by buying from the spot market. However, GENCOs need to play a role in risk management under various contractual arrangements that are intended to reduce the risk of other market players including their own customers (the suppliers, retailers, traders, brokers and end-users). If the reputation of a GENCO is dented, its customers may minimise their risk by opting to trade in the spot market or by entering into short-term/long-term contracts directly with more reputable GENCOs. Moreover, if a GENCO frequently fails to deliver power, it will run the risk of not being accepted by the ISO. Cai et al. [6], Medjoudj et al. [27] and Sullivan et al. [33] look at different reputational attributes and price discounts to analyse the switching behaviour of GENCO's customers to a competitor. Some service attributes, namely reliability, renewable power and customer service/satisfaction, are found to be important factors affecting customers' choice of GENCOs. The GENCOs need to invest in maintaining their customer satisfaction, reliability and reputation to ensure future contracts and enterprise profitability. This cost must be included in the maintenance cost models as the reliability of the GENCO directly depends on the frequency and quality of the maintenance.

The reputational costs ($oppi_{it}$) that the customers may incur during failure or planned maintenance of generator *i* at time *t* will affect the decision in the next electricity supply contract. It can be represented as the "cost of loss in customer trust". The reputation is like customer loyalty to the company due to its good service. This is represented by expression (9):

$$\left\{\begin{array}{ll} oppim_{it} & \text{in case of planned maintenance} \\ oppif_{it} & \text{in case of failure} \end{array}\right\}. \quad (9)$$

Using decision theory terminology, reputational cost may be assessed through *pricing-out* the loss of customer loyalty. This may be interpreted as the maximum price that the supplier is willing to pay in order to avoid losing customer loyalty. We use the AHP [30] to estimate reputational cost. The first step in an AHP is to develop a hierarchical representation of the problem, as shown in Figure 1. At the top of the hierarchy, level 0, stands the goal of the analysis. Level 1 consists of multiple criteria. Level 2 lists the alternatives. The connections between components of different levels indicate relationships between criteria, alternatives and goals.

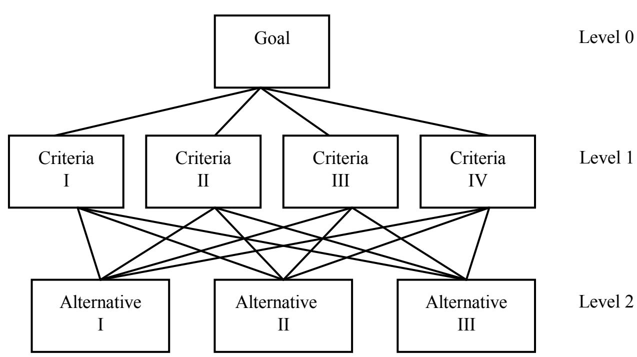

Figure 1: AHP structure

Once the hierarchy has been structured, the priorities of criteria and alternatives at each level are determined. Comparison matrices of all criteria and alternatives in each level with respect to the criteria and alternatives of the immediately higher level are constructed following the priorities, and individual comparative judgments are converted into ratio scale measurements.

The pair-wise comparison is an assessment tool used to determine the relative weight of each criterion and each alternative. It specifies which criterion or alternative is preferable with respect to the goal or the selected criterion. The weights are quantified by using a nine-point scale explained in [30]. The pair-wise comparison works by judging each criterion as to its relative preference/weight to the goal and judging each alternative as to its relative preference to its parent criterion. Judging can be done using a bottom up or top down pair-wise assessment, depending on which is better understood, the criteria or the alternatives. The pair-wise comparisons generate a vector of priorities (with values of relative rankings) for each level of the hierarchy depending on the number of criteria and alternatives at each level.

The maximum Eigen-value (λ_{max}) is calculated from the priority vector and pair-wise assessments by multiplying the priority vector and the sum of weights of each criterion. An example of λ_{max} calculation is shown in Appendix A. λ_{max} is then used to validate whether the pair-wise comparison matrix provides a completely consistent evaluation. The Consistency Ratio (CR) can be obtained using: CI/RI; where, the Consistency Index (CI) for each matrix = (λ_{max} -*n*)/ (*n*-1); where *n* is equal to the order of the comparison matrix. The Random Consistency Index (RI) can be randomly obtained from a large number of simulation runs, and varies depending upon the order of matrix (*n*). Reference [30] shows the average (RI) obtained by approximating random indices using a sample size of 500.

The acceptable CR range varies according to the size of matrix. If the value of CR is equal to, or less than, the acceptable value, this implies that the evaluation within the matrix is acceptable or indicates a good level of consistency in the comparative judgments represented in that matrix. If CR is more than the acceptable value, then the evaluation process should be improved and repeated.

Finally, the weights of the alternatives with respect to each criterion are derived, and then the overall composite weight of each alternative is calculated. The composite weight of the alternative can be used to quantify the reputational cost. A full example of this calculation is given in Appendix A.

3.5.5 *Interruption Cost*

The interruption cost is the economic losses that the customer may incur during a generator failure. An example of interruption cost for a large industrial customer is presented in [33] and is given as expression (10):

$$ICf_{it}(\$) = VLP_{it} + ORC_{it} - ORS_{it} \qquad (10)$$

The Value of Lost Production ($) for generator i at time t (VLP_{it}) is equal to the customer's expected revenue without outage minus its revenue with outage. The Outage Related Costs ($) for generator i at time t (ORC_{it}) are the direct costs incurred because of outages. The Outage Related Savings ($) for generator i at time t (ORS_{it}) are the cost savings from the outages, such as cost of unused fuel and cost of unused raw materials [30].

3.6 Maintenance Cost Model

The complete cost model under no-failure ($Cost\ A_{it}$) represents the cost model when generators are not subjected to failures and includes all maintenance cost components.

$$Cost\ A_{it} = \left[Cma_{it}(s) + opplm_{it} + RCm_{it} + oppim_{it}\right] \tag{11}$$

The cost model with failures ($Cost\ B_{it}$) is the maintenance cost model for the scenario when generators are subjected to failures. This includes all maintenance cost components of (11) and failure related cost components.

$$Cost\ B_{it} = \left[Cma_{it}(s) + opplm_{it} + RCm_{it} + oppim_{it} + Cf_{it}(s) + opplf_{it} + oppf_{it} + RCf_{it} + oppif_{it} + ICf_{it}(s)\right] \tag{12}$$

Both $Cost\ A_{it}$ and $Cost\ B_{it}$ represent maintenance costs in different scenarios. $Cost\ A_{it}$ is the sum of all traditional maintenance costs (material and labour) plus other opportunity costs associated with planned maintenance, such as loss of potential profit, reputational cost and rescheduling cost after planned maintenance. As we can see, this cost represents only the scenario of no-failure between planned maintenance periods with the no-failure probability. $Cost\ B_{it}$ represents the failure scenario taking into consideration failures between planned maintenance periods with the failure probability (f_i). In the failure scenario there exist other failure costs in addition to the maintenance costs presented by $Cost\ A_{it}$.

The total expected maintenance cost ($Exp\ (C_{it})$) = $Cost\ A_{it} \times (1-f_i) + Cost\ B_{it} \times f_i$

$$Exp(C_{it}) = \begin{bmatrix} Cma_{it}(s) + opplm_{it} + RCm_{it} + oppim_{it} \\ + [Cf_{it}(s) + opplf_{it} + oppf_{it} + RCf_{it} + oppif_{it} \\ + ICf_{it}(s)] \times f_i \end{bmatrix} \tag{13}$$

3.7 Generator Maintenance Scheduling Problem Formulation

The generator maintenance scheduling problem can be formulated using integer variables to represent the period in which the maintenance of each unit starts [13]. The variables are bounded by the maintenance window constraints. Suppose $T_i \subset T$ is the set of periods when maintenance of unit i may start, so $T_i = \{t \in T: ep_i \leq t \leq lp_i - d_i + 1\}$ for each i. We define,

$$X_{it}=\begin{cases}1 & \text{if unit i starts maintenance in period t}\\ 0 & \text{otherwise}\end{cases},$$

to be the maintenance start indicator for unit $i \in I$ in period $t \in T_i$. It is convenient to introduce two further sets. Firstly let S_{it} be the set of start time periods such that if the maintenance of unit i starts at period k that unit will be in maintenance at period t, so $S_{it}=\{k \in T_i: t-d_i+1 \leq k \leq t\}$. Secondly, let I_t be the set of units which are allowed to be in maintenance in period t, so $I_t=\{i: t \in T_i\}$. Then the problem can be formulated as below.

The objective function considered for scheduling the maintenance activities is to minimise the expected market maintenance cost given by expression (13). The generator maintenance scheduling problem with the objective function and some of the common constraints is presented below for completeness. This formulation will be used in the case study in Section 4.

$$\underset{X_{it}}{Min} \sum_{t \in T} \sum_{i \in I_t} \left(\sum_{k \in S_{it}} X_{ik} Exp(C_{ik}) \right) \tag{14}$$

This is subject to the following constraints:

- Maintenance window constraints, which define the possible times and the duration of maintenance for each piece of equipment,

$$\sum_{t \in T_i} X_{it} = 1 \quad \textit{for all } i \in I. \tag{15}$$

- Crew constraints, which consider the manpower availability for maintenance work,

$$\sum_{i \in I_t} \sum_{k \in S_{it}} X_{ik} M_{ik} \leq AM_t \quad \text{for all } t \in T. \tag{16}$$

- Load and reserve constraints, which consider the demand and minimum reserve margin of the power system during the scheduling period,

$$\sum_{i \in I} g_{it} - \sum_{i \in I_t} \sum_{k \in S_{it}} X_{ik} g_{ik} \geq L_t + R_t \quad \text{for all } t \in T. \tag{17}$$

Expressions (14)-(17) define a general mathematical model for a general generator maintenance scheduling problem. Further constraints may be imposed involving the reliability, transmission capacity and maintenance in local areas of the power system.

4. Case Study

4.1 Maintenance Cost Data Gathering

In this section we present a case study to demonstrate the development of the expected maintenance cost function discussed in the previous section. We will show the AHP application for calculating the loss of reputation cost. The case study uses the system data presented in [15], which considers three generating units with a capacity of 80 MW, 110 MW and 50 MW over a four week period. The power generating units encompass a single GENCO. All maintenance costs components, which are introduced in $Exp(C_{it})$ given by expression (13), are calculated, except the rescheduling cost since the result of [10] shows that it is less than 0.42% for nine GENCOs, which is considered to be minimal. Therefore, it is ignored in this case study.

Actual maintenance, material and labour data have been gathered from an electricity company. The yearly maintenance report contains maintenance cost data for all segments. We have taken the average maintenance cost for different segments and used it in this example. Table 1 contains the average maintenance cost for one generator. We assume all generators have the same maintenance cost throughout the planning period.

Table 1: Summary of Maintenance Data

Maintenance costs	Yearly	Weekly
Direct labour cost	$3,577,754	$68,803
Indirect labour cost	$889,580	$17,107
Direct material cost	$2,857,160	$54,945
Indirect material cost	$3,867,326	$74,371
Total Maintenance costs	$215,226	

Using the data presented in [16] the Mean Time between Failures (MTBF) (IEEE-RTS generation system) is assumed to be 1200 hours (7 weeks). So, the failure rate is equal to 1/7 = 0.1429 failures per week and the cost of repair or replace is assumed to be $1,000,000. So, the cost of failure is equal to = 0.1429 * 1,000,000 = $142,900. The total expected costs for the three generation units during the four week horizon is calculated, assuming that the probability of failure is 5%, which is towards the higher end of the failure probability [35].

Historical data on MCPs for 1998-2001 of some GENCOs in California are available in [21]. MCPs are assumed not to vary geographically in this study. Since we don't have MCPs values, a normal distribution of historical MCP data will be used to derive the weekly MCP. In doing so, the MCPs' values for weeks 1, 2, 3 and 4 are 36.43 $/MW (flat during the week), 40.71 $/MW, 43.29 $/MW and 37.71 $/MW respectively. With these MCPs, the total cost for one MW-week for weeks 1, 2, 3 and 4 will be $6,120, $6,840 and $7,272 and $6,336 respectively.

Both MCPs and SMPs change over time. As described earlier, the SMP is volatile and is equal to MCP multiplied by (1+ α), where α takes a random value between (-0.9, 9) for each time period, although the average values of MCP and SMP are similar as noted in [5, 24]. For demonstration purposes we set the value of α to 0.05 (i.e. 5%) representing a small volatility and slightly higher value of SMP with respect to MCP, i.e. SMP is equal to *MCP**1.05. Therefore, the SMPs' values for weeks 1, 2, 3 and 4 are 38.25 $/MW (flat during the week), 42.75 $/MW, 45.45 $/MW and 39.60 $/MW respectively and the total cost based on SMPs for one MW-Week for weeks 1 to 4 will be $6,426 , $7,182, $7,636 and $6,653 respectively. Each generator is assumed to supply its capacity in MW (g_i) and the cost curve function is a quadratic cost function as follows:

$$C_i(g_i) = 0.10 g_i^2 + 12 g_i + 100 \ \$ \qquad (18)$$

The cost curve functions for each generator are as follows: The total generation cost for the first generating unit is $C_1(80) = 0.10(80)^2 + 12(80) + 100$ =$1700. There are 168 hours in a week; therefore the total generation cost for a week is $285,600. Similarly, the total generation costs for the second and third units are $441,840 and $159,600 respectively.

Assuming that the GENCO could participate in the day-ahead market to receive MCP rate, the no-bids losses for each unit for a time period can be calculated using expression (4) for the day-ahead market. For example, the no-bids losses for week 1 (i.e. t=1) for each generating unit is calculated as follows: for generating unit 1: 80*6120 – 285,600 = $204,000, for generating unit 2: $231,360, and for generating unit 3: $146,400.

The contractual compensation for each unit for a time period can be calculated using expression (6). For example, compensation for week 1 (i.e. t = 1) for each generator unit are calculated as follows: for generating unit 1: 80(6426) – 80(6120) = $24,480; for generating unit 2: $33,660; and for generating unit 3: $15,300.

Using the data presented in reference [34] the interruption cost for a week for a large commercial and industrial customer is assumed to be equal to $74,835. Calculation for other time periods can be obtained in a similar way and these are summarised in Table 4.

4.2 AHP Application

The literature shows the ability of the AHP in making decisions and solving multi-criteria problems for different applications. Although there are many ways to assess subjective data, the AHP is thought to be appropriate for weighting layered data such as ours in this case study. Similar to AHP applications in telecommunication services [31] and power system operations [27] discussed earlier, the AHP will be used here to model reputational cost. We investigate and model GENCOs' reputational cost that is affected by maintenance activities of generators using the AHP. The AHP hierarchy is constructed by the goal at level 0, then the criteria in the first level and finally the alternatives in the last level.

The competition in the deregulation environment is expected to promote their services to meet customer expectation. Therefore, GENCOs are expected to lose customers if they fail to deliver these expectations [6, 33]. In a market environment, criteria such as efficiency, technical support and customer satisfaction should be considered in order for GENCOs to compete with each other to win their market share and remain in business. In this case study, the criteria are selected based on direct questions to a decision maker of the electricity company. We have conducted an interview with decision makers (five directors) in an electricity company. The interview took into consideration the information presented in [6, 33] which indicate that technical support and customer satisfaction are very important for customer relations. Also they have two criteria in mind which are very important; reputation and discount. A telephone survey with decision makers in another two companies was conducted and the result is similar to the previous interview result. They all agree that technical solution is a very important criterion. Table 2 explains the criteria (some are discussed in [2]), which are used in our case study.

Table 2: Criteria classifications

N	Criteria	Explanations
1	Technical Solution (TS)	Provide Uninterrupted Power Supply (UPS), or deployment of portable power generator in case of failure
2	Reputation (Rep)	Maintain excellent reputation among other competitors
3	Customer Satisfaction (CS)	Maintain excellent customer satisfaction by pleasing them and providing good services
4	Discount (Dis)	Give discount on price of electricity

As described in [2], a Service Level Agreement (SLA) is a formal negotiated agreement between a customer and the service provider to provide a service at a performance level that meets or exceeds the specified objectives (criteria). Managed telecommunications services are typically governed by a multiyear contractual SLA and measured using Key Performance Indicators (KPIs). For each SLA, one or more KPI is required. If the contractor fails to meet any of the KPIs for an SLA for a given month, then the contractor is subjected to penalties and may lose future contracts.

The alternatives are at the last level of the hierarchy. Similarly to telecommunications services, the SLA concept will be used in defining the alternatives. Three alternatives (loyalty models - LMs) are classified to reflect the different services which

GENCOs are expected to provide with a specific cost according to the selected criteria, as explained in Table 3. The cost corresponds to the quality of loyalty model (i.e. services), assuming that the best loyalty model will have the highest cost.

Table 3: Alternative (loyalty models) explanation (H-High Focus, M-Medium Focus, L-Low Focus)

Loyalty models	**Criteria**			
	TS	Rep	CS	Dis
LM-A	H	M	L	H
LM-B	M	M	L	M
LM-C	L	M	H	M

The selection of the best alternative depends on the criteria, where each alternative (loyalty model or service level agreement) has different weights for each criterion. For example, if LM-A is chosen to be the best model, then the GENCOs are expected to account for the cost of maintaining those criteria in the total generator's maintenance cost in order to avoid reputational cost. The cost of LM-A will be quantified using MCP to reflect the real situation of the deregulated environment.

The AHP procedure, as described above and in section 3.5.4, is implemented for the three unit case study of section 4.1 in Appendix A. This selects a loyalty model to price out the loss of GENCO's reputation (reputational cost). As demonstrated in Appendix A, if we use LM-A to price "reputational cost" during failure ($oppif_{it}$) or planned maintenance ($oppim_{it}$) of generating units, then the reputational cost for generator i at time t is equal to: Composite weight of the LM-A * $g_{it,sched}$ MCP_t. The composite weight of LM-A alternative, as calculated in Appendix A is 0.6402, therefore the reputational cost during failure or planned maintenance for generating unit 1 at time 1 (week 1) is equal to: 0.6402* 80 * 6,120 = $313,442.

Similarly, the reputational costs for the other generator units can be calculated. Also, different loyalty models may be used to price the failure and planned maintenance scenario, since the effect of the latter scenario is less than the former because the customer will know about the planned maintenance in advance and can prepare for it. This value, together with other maintenance costs, is added to the maintenance cost model to represent the opportunity cost in the maintenance scheduling of a deregulated power system. Table 4 represents the estimated values for the maintenance cost components for the three generating units for four time periods. The result shows that overall maintenance costs can increase significantly compared to the maintenance costs being considered in previous publications [15, 22, 32]. This cost model should be used in planning and scheduling the maintenance activities of generators as well as identifying the best maintenance strategies over a period of time as they consider failure and opportunity costs.

Table 4: Maintenance Cost Components (in $)

WEEK	UNIT	Direct and indirect	Cost of failure	No-bids losses	Compen-sation cost	Reputa-tional cost	Inter-ruption cost	Maintenance cost without Reputational and Interruption costs			Maintenance cost with Reputational and Interruption costs		
								Under no-failure (Cost A)	Under failure (Cost B)	Total expected cost	Under no-failure (Cost A)	Under failure (Cost B)	Total expected cost
1	1	215,226	142,900	204,000	24,480	313,442	74,835	239,706	661,441	260,793	553,148	974,883	574,235
	2	215,226	142,900	231,360	33,660	430,983	74,835	248,886	697,981	271,341	679,869	1,128,964	702,323
	3	215,226	142,900	146,400	15,300	195,901	74,835	230,526	594,661	248,733	426,427	790,562	444,634
2	1	215,226	142,900	261,600	27,360	350,317	74,835	242,586	721,921	266,553	592,903	1,072,238	616,870
	2	215,226	142,900	310,560	310,560	481,686	74,835	525,786	1,054,081	552,201	1,007,472	1,535,767	1,033,887
	3	215,226	142,900	182,400	17,100	218,948	74,835	232,326	632,461	252,333	451,274	851,409	471,281
3	1	215,226	142,900	296,160	29,088	372,443	74,835	244,314	758,209	270,009	616,757	1,130,652	642,452
	2	215,226	142,900	358,080	39,996	512,109	74,835	255,222	831,037	284,013	767,331	1,343,146	796,122
	3	215,226	142,900	204,000	18180	232,777	74,835	233,406	655,141	254,493	466,183	887,918	487,269
4	1	215,226	142,900	221,280	25,344	324,505	74,835	240,570	679,585	262,521	565,075	1,004,090	587,025
	2	215,226	142,900	255,120	34,848	446,194	74,835	250,074	722,929	273,717	696,268	1,169,123	719,911
	3	215,226	142,900	157,200	15,840	202,815	74,835	231,066	606,001	249,813	433,881	808,816	452,628

5. Application of Cost Models in Maintenance Scheduling

This section briefly discusses the utilisation of the developed cost models in generators' maintenance schedules to investigate the impact of the reputational cost on the AHP loyalty models. First we look at the same test system with three generating units over a four week planning horizon, as discussed in the previous section. The scheduling problem has maintenance window, sequence, load and non-simultaneous maintenance constraints. The relevant scheduling problem data and constraints are taken from [15]. The objective function considered for scheduling the maintenance activities is to minimise the market expected maintenance cost given by expression (14).

The different components of the maintenance costs have been calculated in a previous section and are presented in Table 4. A set of experiments was conducted using a genetic algorithm-based solution technique to obtain an optimised maintenance schedule as described in [12, 13] for four scenarios. The evaluation (fitness) function is formulated as a weighted sum of the objective function and the penalty function for violations of the constraints in this example, taking a similar approach to that described in [13].

The first scenario was without including opportunity costs (i.e. without the reputational and interruption costs). The optimum schedule that satisfied all constraints is shown Figure 2. The black bar indicates the maintenance state of the generators.

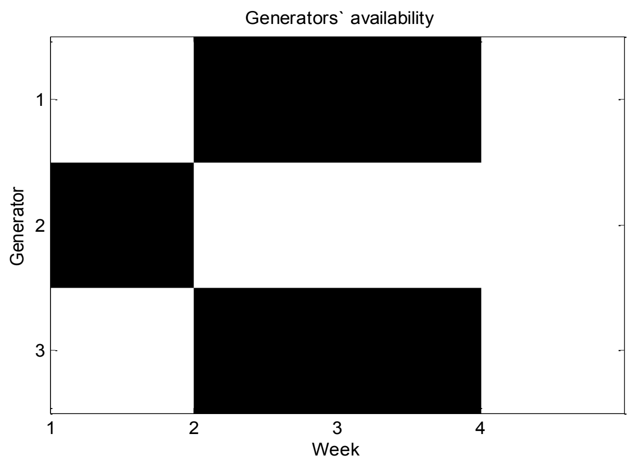

Figure 2: The optimum solution

The other three set experiments were conducted including the reputational and interruption costs in the maintenance scheduling model with Loyalty Model A (LM-A), Loyalty Model B (LM-B) and Loyalty Model C (LM-C) to model the reputational cost respectively. In all experiments the optimum solution obtained was the same schedule as shown in Figure 2, but with different cost values. The highest cost value is obtained in the experiment where we use the best loyalty model (LM-A) for quantifying reputational cost. However, the lowest cost was obtained in the experiment where we use the poor loyalty model (LM-C). The result shows that customer-related costs are critical factors impacting on the overall maintenance costs' value; therefore they must be considered and carefully modelled in order to obtain the optimum solution. We may conclude that Loyalty Model A can be used for pricing out reputational cost for strategic customers and Loyalty Models B and C for other customers.

It is worth noting here that the optimum schedule obtained in all experiments in this small test problem is the same, which does not show the effect of the losses of reputational and interruption costs in the schedule. This is because we consider the opportunity cost over all the planning period to be the same. Also, the problem has a tight schedule and a very small search space.

In order to demonstrate the effect of the reputational and interruption costs in the maintenance planning and scheduling, a set of experiments with a 21-unit test problem over 52 weeks taken from [13] were conducted. All data gathering, formulation and solution methodologies carried out for the 21 generating unit system in the similar way as for the 3-unit system described in previous sections. Two sets of experiments were conducted: without consideration of reputational and interruption costs, and with consideration of the reputational and interruption costs. These costs are time dependent in this case study, i.e. they are different in different time periods for the generators. For example, the reputational costs for units 1, 5 and 9 are shown in Figure 3.

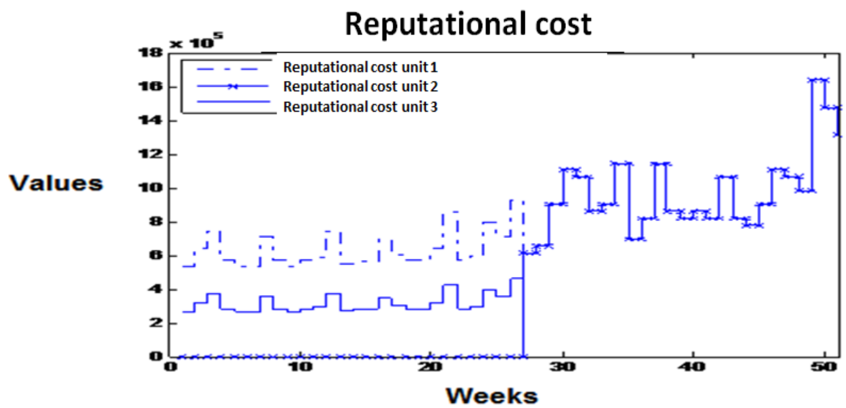

Figure 3: Reputational costs for units 1, 5 and 9

In case of no consideration of the reputational and interruption costs, the best schedule obtained is shown in Figure 4, where the black bars indicate the generator is down for maintenance. For example, generator 1 starts maintenance at week number 13 and will stay down for seven weeks (till week 20) since the maintenance duration is seven weeks.

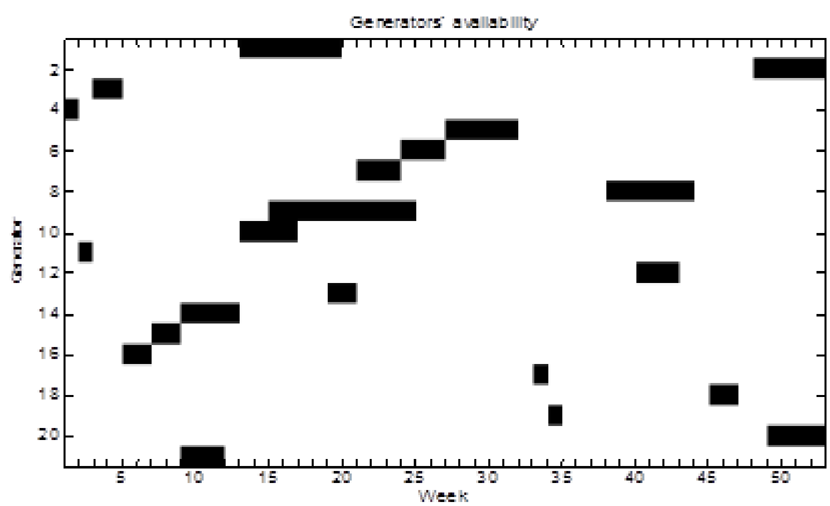

Figure 4: Maintenance schedule without considering the reputational and interruption costs

With consideration of the reputational (using Model A) and interruption costs, the best schedule obtained is shown in Figure 5, where for example, generator 1 starts maintenance at week number 1 and will stay down for seven weeks.

Comparison of the results shows that the previous optimum schedule becomes no more optimal because of the consideration of the reputational cost. We can see that the reputational cost has an effect on both schedule and maintenance cost value. The schedule in Figure 5 shows that the generators try to avoid maintenance in the periods where reputational cost is high. For example for unit number 5 we can see that the start week of maintenance is 32 (during the allowed period of maintenance (27-52)) where the value of reputation is low.

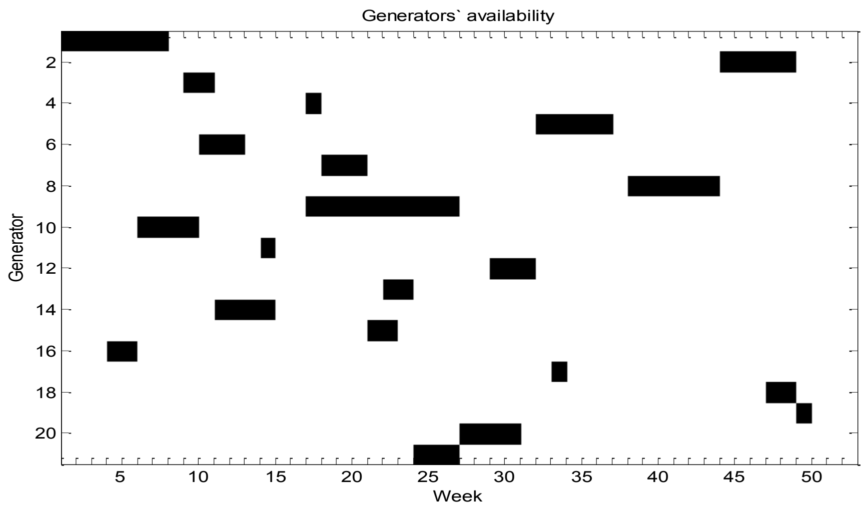

Figure 5: Maintenance schedule with consideration of the reputational and interruption costs

6. Conclusions

The maintenance cost has been modelled in the literature with several representations for centralized power systems [15, 22, 32]. With deregulation of power industries in many countries, the costs representation to be used within the maintenance model in the decentralized power systems has become an important research question. In this paper we have analysed maintenance cost representations considering the direct, indirect and opportunity costs to include in a maintenance scheduling model. We demonstrated the data gathering process for different maintenance cost components. Two models are developed in this paper reflecting the failure and no-failure status of a generator. The paper shows that other costs that affect the decisions with respect to the timing of generator maintenance should be taken into account. Also, the models account for any sudden failure which may happen before or after any planned maintenance event. The opportunity costs which reflect GENCOs' reputation from the viewpoint of their customers in case of a failure are also considered.

In the case of maintenance or failure, the GENCOs must minimise their reputational cost and that is equal to keeping customer loyalty in either case. The cost of maintaining customer loyalty should be added to the total maintenance cost of GENCOs. The paper presented an application of the AHP to identify the best loyalty model for GENCOs to select in order to price out "reputational cost" in deregulated power systems which will help in minimising total maintenance cost. This model reflects the current situation in the deregulated environment. The experimental results with maintenance scheduling case studies demonstrate the effect of the new cost model in the maintenance cost and optimal schedule.

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Appendix A

Following the discussion in Section 4.2 we demonstrate the procedures of the AHP implementation to select a loyalty model and to price out reputational cost, see the case study (three generators over four time periods) described in Section 4.1. The decision maker judges the importance of each criterion in pair-wise comparisons. The result of the AHP is a prioritized ranking of each alternative. The weight of the alternatives will handle the minimisation of reputational cost in maintenance scheduling of power generators. The hierarchy is constructed by following the AHP steps as below:

- The goal is to determine the best loyalty model that minimises reputational cost (level 0)
- Criteria are presented in Table 2 (level 1)
- The alternatives are Loyalty Model A (LM-A), Loyalty Model B (LM-B), and Loyalty Model C (LM-C) (level 2)

We need a comparison matrix of 4 by 4, which corresponds to pair-wise comparisons between four criteria with respect to the goal for level l, as shown in Table 5, and four comparison matrices at level 2 of size 3 by 3 (one of them is shown in Table 5). Four criteria are placed in Table 5 forming the first matrix using the scale presented in [30]. We set the diagonal equal to one (a_{ii} =1). Furthermore, we set $a_{ij} = k$, and we set $a_{ji} = 1/k$, where the value of k is subjectively determined by the decision maker using a scale of preference. A basic, but very reasonable, assumption is that if criterion X is absolutely more important than criterion Y and is rated at 9, then Y must be absolutely less important than X and is valued at 1/9.

These pair-wise comparisons are carried out for all criteria presented in Table 2. There is no standard way to make the pair-wise comparison but let us suppose that the decision maker decides that (TS), is slightly more important than the (Rep), and much more important than (CS) and far more important than (Dis) . In the next matrix that is rated as 3 in the cell (TS), (Rep) and 1/3 in (Res), (TS). Also, it is rated as 7 in the cell (TS), (CS) and 1/7 in (CS), (TS) and it is rated as 9 in the cell (TS), (Dis) and 1/9 in (Dis), (TS). The decision maker also decides that (Rep) is more important than (CS) and (Dis), giving the same judgment 5 in (Rep), (CS) and (Rep), (Dis) and giving 1/5 value to (CS), (Rep) and (Dis), (Rep). Also, the decision maker similarly judges that (CS), is slightly more important than (Dis), (rating = 3). This forms the completed matrix as shown below.

Table 5: Pair-wise comparison matrix for level 1 with respect to goal

Criteria	TS	Rep	CS	Dis
TS	1	3	7	9
Rep	0.33	1	5	5
CS	0.14	0.20	1	3
Dis	0.11	0.20	0.33	1
Sum	1.58	4.40	13.33	18.00

The overall weight assigned to each criterion is between 0 and 1, and the total weights will add up to 1. We do that by taking each entry and dividing by the sum of the column it appears in. The normalized weights for each criterion are presented in Table 6.

Table 6: Normalized weights and priority vector for each criterion in level 1

Criteria	TS	Rep	CS	Dis	Sum	Priority
TS	0.630	0.682	0.525	0.500	2.337	58.42%
Rep	0.210	0.228	0.375	0.278	1.090	27.25%
CS	0.090	0.045	0.075	0.167	0.377	9.43%
Dis	0.070	0.045	0.025	0.055	0.196	4.90%
Sum	1.000	1.000	1.000	1.000	4.000	100.0%

The priority vector for each criterion is equal to the average, for example it is equal to 2.337/4 =0.5842 for TS, 0.2725, 0.0943, 0.0490 for Rep, CS and Dis respectively. These values are presented in the last column of Table 5.

The maximum Eigen-value (λ_{max}) is calculated by multiplying the priority vector by the sum of the weight of each criterion. λ_{max} is used to validate whether the pair-wise comparison matrix provides a completely consistent evaluation [30]. The CR can be obtained using: CI/RI;

$\lambda_{max} =$ (0.5842)(1.58)+(0.2725)(4.40)+(0.0943)(13.33)+(0.0490)(18.00) = 4.2611

Where, the CI for each matrix is equal to the following: $CI = (\lambda_{max} - n)/n\text{-}1$ = (4.2611- 4)/3 = 0.087

Referring to [30] the RI is equal to 0.89 for n =4 and the acceptable consistency is about 10% or less.

$CR = CI/RI$ = 0.087/0.89 = 9.78%, acceptable.

Since the value of CR is less than 10%, the inconsistency is acceptable. Then, the same analysis can be performed for level 2. The comparison matrices are made for each alternative, with respect to each criterion. Using the same methodology for developing the level 1 comparison matrix, three alternatives (loyalty models) are placed in Table 7 forming the first matrix for level 2.

Table 7: Pair-wise comparison matrix for level 2 with respect to TS

Alternatives	LM-A	LM-B	LM-C
LM-A	1	3	7
LM-B	0.33	1	5
LM-C	0.14	0.20	1
Sum	1.47	4.20	13.00

The priority vector for each alternative is equal to the average of its normalized weights. These values (for level 2 with respect to TS) are presented in the last column of Table 8.

Table 8: Normalized weights and priority vectors for level 2 with respect to TS

Alternative	LM A	LM B	LM-C	Sum	
LM-A	0.677	0.714	0.538	1.929	64.30%
LM-B	0.226	0.238	0.385	0.849	28.30%
LM-C	0.097	0.048	0.077	0.222	7.40%
Sum	1.00	1.00	1.00	3.000	100.0%

The maximum Eigen-value (λ_{max}), CI and CR are calculated by using the same methodology discussed earlier. Referring to [30] the RI is equal to 0.52 for n =3 and the acceptable consistency is about 10% or less. Therefore: λ_{max} = 3.097, CI = 0.0484, *CR* = 9.30% < 10%, acceptable.

Regarding the Rep criteria, using the same methodology discussed earlier, the pair-wise comparison matrix for level 2 with respect to Rep was developed and the result shows that: λ_{max} = 3.055, CI = 0.0277, CR = 5.32% < 10%, acceptable. However, we do not use the paired comparison matrix for level 2 with respect to criteria III and IV (i.e. CS and Dis), because their weights are very small. Therefore, we can assume that their weights are set as zero [30]. So, the weight of criteria I and II must be adjusted so that the sum is still 100%. Adjusted weight for TS = 0.5842/ (0.5842+0.2725) = 0.6819, and Rep = 0.2725/ (0.5842+0.2725) = 0.3181. Then, we compute the overall composite weight of each alternative based on the weight of level 1 and level 2. The overall weight is the normalisation of the linear combination of multiplication between weight and priority vector.

Table 9: Overall composite weight of the alternatives

	Technical Solutions	Reputations	Composite Weight
(Adjusted) Weight	0.6819	0.3181	
LM-A	64.30%	63.43%	64.02%
LM-B	28.30%	26.02%	27.57%
LM-C	7.40%	10.55%	8.41%

The overall consistency of the hierarchy is given by:

$$\overline{CR} = \sum_i w_i \, CI_i \,/ \sum_i w_i RI_i \tag{19}$$

= [0.087(1) + 0.0484(0.6819) + 0.0277(0.3181)]/ [0.89(1) + 0.52(0.6819) + 0.52(0.3181)] = 9.14 %< 10%, acceptable.

The final result presented in Table 9 shows that two criteria, TS and Rep are the most important criteria since they have high weights. LM-A is the best model; LM-B becomes second best and LM-C is third. LM-A is the best model with a weight of 0.6402 with respect to both TS and Rep criteria. Therefore, in the case of a failure or planned maintenance, GENCO may provide alternative power and maintain an excellent reputation in order to have customer loyalty. LM-B may offer a lower probability technical solution, such as offering an uninterrupted power supply that can be sustained for a short time. Regarding LM-C, offering a lesser service than LM-B, makes it the third choice.

If we use LM-A to price "reputational cost" during failure ($oppif_{it}$) or planned maintenance ($oppim_{it}$) of generating units, then the "reputational cost" cost for generator *i* at time *t* is equal to: Composite weight of the LM-A * $g_{it,sched}$ MCP_t. For example, we assume that the reputational cost during failure or planned maintenance for generating unit 1 at time 1 (week 1) is equal to: 0.6402* 80 * 6120 = $313442.

Similarly, the reputational cost for the other generating units can be calculated. Table 4 represents the estimated values for the reputational costs for the three generating units over four time periods.